STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	
Proposed General Increase	:	
In Rates For Gas Service	:	No. 14-0224
	:	and
	:	No. 14-0225
The Peoples Gas Light and Coke Company	:	Consol.
	:	
Proposed General Increase	:	
In Rates For Gas Service	:	

Rebuttal Testimony of

DEBRA E. EGELHOFF

Manager, Gas Regulatory Policy
Integrys Business Support, LLC

On Behalf of
North Shore Gas Company and
The Peoples Gas Light and Coke Company

TABLE OF CONTENTS

Page

I. INTRODUCTION AND BACKGROUND

A. Identification of Witness

Q. Please state your name and business address.

A. My name is Debra E. Egelhoff. My business address is 200 East Randolph Street, Chicago, Illinois 60601.

Q. Are you the same Debra E. Egelhoff who provided direct testimony on behalf of The Peoples Gas Light and Coke Company ("Peoples Gas") and North Shore Gas Company ("North Shore") (together, "the Utilities") in these consolidated dockets?

A. Yes.

B. Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to the rate design, tariff and rider issues raised in the direct testimony of Illinois Commerce Commission ("Commission" or "ICC") Staff ("Staff") witnesses William R. Johnson and Dianna Hathhorn; the Office of the Attorney General ("AG") and the Environmental Law & Policy Center ("ELPC") witness Scott J. Rubin; the AG witnesses Roger D. Colton and David J. Effron; the Illinois Industrial Energy Consumers ("IIEC") witness Brian C. Collins; and the City of Chicago ("City"), Citizens Utility Board ("CUB"), and IIEC (together, "CCI") witness Michael P. Gorman. Specifically, my rebuttal testimony addresses:

1. The recommendations made by Mr. Johnson, Mr. Rubin, Mr. Colton, and Mr. Collins regarding the Utilities' proposed rate designs.

2. The recommendations made by Ms. Hathhorn regarding Rider QIP, Qualifying Infrastructure Plant.
3. The statements made by Mr. Effron and Mr. Gorman regarding Rider QIP adjustments.

C. Summary of Conclusions

Q. Please summarize the conclusions of your rebuttal testimony.

A. In my rebuttal testimony, I conclude that the Utilities' proposed rates arising from their proposed revenue requirements and rate designs are appropriate, based on sound ratemaking principles, and are consistent with recent Commission orders. Additionally I conclude:

- Staff witness Mr. Johnson's and AG/ELPC witness Mr. Rubin's proposals to limit the recovery through customer charges to customer costs or less are flawed.
- AG witness Mr. Colton provides no sound basis to set fixed cost recovery based on the alleged impact to low income and elderly customers.
- IIEC witness Mr. Collins does not provide support for his across-the-board revenue increase.
- Changes to the Rider QIP tariff should be accepted.
- AG witness Mr. Effron and CCI witness Mr. Gorman incorrectly conclude that unwarranted reductions to the 2014 QIP additions pose little to any risk to Peoples Gas.

D. Itemized Attachments to Rebuttal Testimony

Q. Are there any attachments to your rebuttal testimony?

A. Yes. I am sponsoring, and have attached hereto, the following exhibits:

- NS-PGL Exhibit ("Ex.") 29.1 – Revised Rider QIP, Qualifying Infrastructure Plant
- NS-PGL Ex. 29.2 – Certificates of Publication

II. FIXED COST RECOVERY

Q. Staff witness Mr. Johnson and AG/ELPC witness Mr. Rubin each use the term "SFV". What is an SFV rate design?

A. As explained in my direct testimony (Egelhoff Dir., NS Ex. 15.0, 15:301-306; Egelhoff Dir., PGL Ex. 15.0 REV, 14:300 – 15:305) an SFV (or straight fixed variable) rate design recovers all of a utility's fixed costs through a fixed charge. The ICC has used the term for rate designs approved for Ameren Illinois Company gas utilities ("Ameren") and Northern Illinois Gas Company d/b/a Nicor Gas Company ("Nicor") to mean 80% of fixed costs recovered through fixed charges, but that is not a standard definition. Instead, this could be considered a modified SFV rate design where a large percentage of fixed costs are recovered through fixed charges. It is imprecise to use the term SFV to mean any percentage (other than 100%) recovery of fixed costs through fixed charges.

Q. What is the rate design principle underlying an SFV rate design?

A. SFV rate design separates fixed costs related to gas distribution service (*i.e.*, costs incurred in order to provide service, regardless of how much gas is used) from costs that vary with customer usage (which are largely within the control of the customer). It sends the most accurate price signals about the costs of delivery service. Recovering fixed costs through a variable distribution charge sends an incorrect price signal to customers that the more gas they use the more it costs the Utilities to provide them delivery service.

Similarly, placing fixed cost recovery in variable distribution charges incorrectly signals that lower usage reduces the Utilities' costs to provide delivery service. Additionally, SFV rate design reduces the volatility of customers' bills. Customers would pay a fixed monthly charge and the delivery portion of their bill would be unaffected by variations in weather or other conditions. As a result, they would not over or under pay for the services that they receive. A SFV rate would also lower the delivery charge portion of a customer's bills during the winter period when gas usage and market commodity prices are typically at their highest.

Q. Do the Utilities currently have or are they proposing an SFV rate design for any of their service classifications?

A. The Utilities do not currently have an SFV rate design. Under present rates, as approved by the Commission, Service Classification ("S.C.") No. 1 NH[1] for both Utilities is set at 80% recovery which, based on the Commission's Ameren and Nicor orders, could be considered a modified SFV rate design. The other service classifications, however, are not even close to an SFV or even a modified SFV rate design. In the current proceeding the Utilities, as in their recent rate filings, are proposing a gradual movement of increased fixed cost recovery in fixed charges and are requesting for S. C. No. 1 HTG 80% and 75% of fixed cost recovery in the fixed customer charge for North Shore and Peoples Gas, respectively. The proposals for the other service classifications remain far below a modified SFV rate design based on the Commission's previous orders.

[1] As in my direct testimony, I will use "NH" to refer to the non-heating S.C. No. 1 rates and "HTG" to refer to the heating S.C. No. 1 rates.

Q. The Utilities each have a decoupling mechanism in place for S.C. Nos. 1 and 2 (Rider VBA, Volume Balancing Adjustment). Why do they also need to have higher fixed cost recovery in fixed charges?

A. As mentioned in my direct testimony and as Staff (although not the AG) witness acknowledged, Rider VBA is on review before the Supreme Court of Illinois. It is likely that a Court ruling will not be issued while the record in this case is open, and I discuss this further in Section III of my testimony. Furthermore, even with Rider VBA, increasing the fixed cost recovery in the fixed customer charges would better align the charges with the Utilities' underlying fixed costs and would also reduce the magnitude of adjustments that would need to be generated under Rider VBA. Increasing fixed cost recovery through fixed customer charges also evens out a customer's annual bill throughout the year, which mitigates the impacts on customers of higher winter bills, especially during a colder than normal winter. This benefit exists with or without Rider VBA.

The Staff and AG proposals to shift costs to variable charges is even more problematic in light of the uncertainty about Rider VBA. If the Court rules that the Commission lacked authority to approve Rider VBA both the customers and the Utilities are at risk. Customers are at risk for over-paying (*i.e.*, paying more than the approved revenue requirement) in a colder than normal winter (as would have been the case these past two winters) and the Utilities are at risk for under-recovery of approved fixed costs (*i.e.*, billing less than the approved revenue requirement) in a warmer than normal winter.[2] Rider VBA prevents that situation. Absent Rider VBA, only SFV rate design prevents that occurrence, and a modified form of SFV rate design alleviates it.

Q. Staff witness Mr. Johnson analogizes Rider VBA to the effects of the Energy Infrastructure Modernization Act ("EIMA") that applies to the large Illinois electric utilities. Is that an apt analogy?

A. No. Rider VBA is a decoupling mechanism that reconciles the distribution revenues actually billed to customers to a revenue requirement approved by the Commission in the Utilities' latest rate case proceedings. Under Rider VBA, utility costs are determined in the rate case when establishing the approved revenue requirement. Rider VBA does not provide for the recovery of any costs outside of the approved revenue requirement, nor does it allow adjustments based on actual costs being more or less than the approved revenue requirement. Although I am not an expert on EIMA, sometimes called "formula rates", the reconciliation is clearly far more reaching than a simple true-up of amounts billed to customers to an approved revenue requirement. EIMA looks at all actual non-fuel costs in its reconciliation. With what I understand are some limits, the EIMA process takes into account higher or lower costs. Commission orders for utilities operating under EIMA do not support Mr. Johnson's rate design proposals in this proceeding.

Q. Staff witness Mr. Johnson and AG/ELPC witness Mr. Rubin each makes recommendations that, in part, include the concept of limiting the customer charge to recovery of customer-classified costs. Do the Utilities agree?

[2] While weather is the common reason, other factors that cause more or less gas than forecasted to be consumed – such as, for example, economic conditions and adoption of conservation measures – also can create these risks of customers over-paying or the Utilities under-recovering.

A. No. Fixed costs belong in fixed charges. For S.C. Nos. 1 and 2, this is the Utilities' customer charge. Customer-classified costs are some, but not all, of the Utilities' fixed costs. Both Messrs. Johnson and Rubin would place recovery of demand-classified costs, which are likewise fixed costs, in distribution charges. The Commission has endorsed policies in several rate proceedings to increase fixed cost recovery through fixed charges. These proceedings are mentioned in my direct testimony (Egelhoff Dir., NS Ex. 15.0, 13:277 – 14:291; Egelhoff Dir., PGL Ex. 15.0 REV, 13:277 – 14:290). Additionally, some recent cases that Mr. Johnson cites are electric utilities with rates determined under EIMA, and that is not analogous for the reasons previously stated.

Q. In your direct testimony (Egelhoff Dir., NS Ex. 15.0, 9:176-178; Egelhoff Dir., PGL Ex. 15.0 REV, 9:175-177), you stated that all of the Utilities' costs are fixed. What is your definition of "fixed" costs?

A. As stated above, fixed costs are those costs related to gas distribution service (*i.e.*, costs incurred in order to provide service, regardless of how much gas is used). Although these costs in total can increase or decrease due to overall changes in the Utilities' system infrastructure (*e.g.*, number of meters, placement of meters, size of main or services), they do not fluctuate due to the amount of gas customers use.

Q. If Staff witness Mr. Johnson is correct that demand-classified costs vary based on a customer's demand, is he correct that those costs should be recovered through a charge based on usage and not a fixed charge?

A. No. He is correct that demand costs, by definition, are driven by customer demand on the peak day. However, demand costs are fixed costs. As previously stated, fixed costs do not fluctuate as a result of how much gas is used. It is true that the demand on the

Utilities' systems as a whole could fluctuate, but the infrastructure that is put in place to handle the demand will cost the same regardless of the amount of demand that is placed on the system at any given time. As Utilities witnesses Mr. Mark Kinzle (Kinzle Dir., NS Ex. 8.0, 4:75-79) and Mr. David J. Lazzaro (Lazarro Dir., PGL Ex. 8.0 REV, 5:91-95) explained, a primary consideration in system design is to meet design day demand. Thus, the fact that demand may vary from year-to-year (*i.e.*, the fact that system demand and any given customer's demand may vary, with higher peak day gas use in some years than others), does not mean the fixed costs (customer and demand) of the system change with the total of a specific customer's usage. Placing demand classified cost recovery in the variable distribution charge would mean that, irrespective of a customer's demand on the peak day, lower usage on other days would reduce the customer's contribution to demand cost recovery. In fact, under Staff and intervenor proposals, a customer's peak day demand could increase but if his overall usage declined, his contribution to demand cost recovery would decline.

Q. Staff witness Mr. Johnson's response to the Utilities' data request Staff NS-PGL 2.30 states that demand costs would be recovered through the distribution charge if a service class does not have a demand charge. Do you agree?

A. No. As previously stated, demand costs are fixed costs. Although demand related costs may be spread among rate classes using certain usage based allocation methodologies, demand-related costs do not vary with customers' usage and cost-based ratemaking does not require that they be recovered through distribution charges. There is often disagreement on how to allocate demand-related costs. In fact, the Gas Distribution Rate Design Manual Prepared by the National Association of Regulatory Utility

Commissioners ("NARUC") Staff Subcommittee on Gas (June 1989) states on pages 49-50:

> The most controversial issue is deciding where capacity [demand] costs belong in the rate. Because they are fixed costs, it is sometimes argued that they should be part of the customer charge. On the other hand, it can be argued that … those common fixed costs should be recovered evenly from all units of commodity sold. It is even occasionally proposed that these costs be spread between customer and commodity [distribution] charges.

This passage reiterates that demand-related costs are fixed, and that there are a few acceptable methodologies for recovering such costs. The Utilities believe that consistent with accepted methodologies and recent Commission policy, such fixed costs should be recovered through a fixed charge such as the customer charge. In the interest of rate design continuity and gradualism, in this proceeding the Utilities propose to spread such costs between the customer and distribution charges for all service classifications without a demand charge (S.C. Nos. 1 NH, 1 HTG, 2, and 8).

Q. Staff witness Mr. Johnson and AG/ELPC witness Mr. Rubin discuss encouraging conservation as support for their rate design proposals. Under the Utilities' rate design proposals, are customers able to reduce their bills by reducing gas usage?

A. Yes. Under the Utilities' proposed rate design a large portion of a typical S.C. No. 1 HTG annual bill before taxes would be derived from variable charges (approximately 60% for Peoples Gas and 70% for North Shore). A customer can reduce the distribution charge portion of their bill through adoption of utility-program energy efficiency ("EE") measures and conservation activities. Further and more significantly, customers also realize the benefits of EE measures and conservation through lower gas costs. Under any rate design, gas costs remain one of the largest portions of an average residential heating customer's annual bill, with the cost of gas constituting approximately 40% for Peoples Gas and 55% for North Shore. The market prices of gas, assessed to customers through the gas charge, send the proper price signals to participate in the Utilities' EE programs and to adopt other conservation measures. These are "real" savings and "real" incentives for customers to reduce usage through conservation. Thus, reducing usage produces significant bill reductions that are beneficial to customers across all income levels and housing-types.

Q. Do you agree with the AG/ELPC witness Mr. Rubin that greater use of fixed charges in the Utilities' rate designs runs counter to Public Utilities Act Section 8-104's overall goal of reducing energy usage (Rubin Dir., AG/ELPC Ex. 3.0, 20:424-427)?

A. No. As I understand the Utilities' EE programs, as approved by the Commission in Docket 13-0550, the Utilities are to achieve statutorily-required energy efficiency goals, through customer participation in the approved programs. The Commission approved a budget and the Utilities recover the costs of their EE programs through their Rider EOA, Energy Efficiency and On-Bill Financing Adjustment. I am advised by counsel that Section 8-104(c) of the Public Utilities Act has capped the recovery of the Utilities' EE spending at 2% of the Utilities' total revenues, subject to certain adjustments. While I am not an attorney, I believe that the legislature and Commission intend that costs related to conservation and EE measures occur within the context of the Utilities' approved EE compliance plans and not through rate design that sends incorrect price signals.

Q. Are you aware that the Commission Order in Docket No. 13-0550 required changes to the Utilities' rate structure to achieve the required energy efficiency goals?

A. While I am not an attorney, the Commission's Findings and Orderings provide for no adjustments, modifications or new rate design. Notably, under Rider EOA, the Utilities do recover the cost of implementing their EE programs through volumetric charges.

Q. Would a rate design with more costs recovered in variable charges encourage more conservation, and, if so, why is that not a preferable rate design?

A. Through the Section 8-104 programs and the decision to provide for volumetric cost recovery under Rider EOA, the Commission has provided a very clear signal as to how the Utilities are to implement and recover costs for their EE programs. In the context of rate design, a wider variety of factors must be considered. As Utilities witness Ms. Joylyn Hoffman Malueg explained in the context of the embedded class cost of service study ("ECOSS"), which is the starting point for rate design, "[c]ost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer classes." Hoffman Malueg Dir., NS Ex. 14.0, 7:139-140; Hoffman Malueg Dir., PGL Ex. 14.0, 7:141-142. The Utilities' gas distribution service to residential customers in single family homes and multi-family buildings is entirely driven by fixed costs. The mere presence of the customer for a particular account drives the nature of the cost of the utility service (***e.g.***, the meter, the service line and the main) to that premises. Outside of cost causation, there are other reasons why more variable rate designs are not preferable. A rate design with more variability gives the customer greater exposure to fluctuations in usage due to gas price locations and weather-related demand. A greater percentage of fixed costs through fixed charges reduces the potential for cross-subsidization between low usage and higher usage customers.

III. ALTERNATIVE RATE DESIGN PROPOSAL

Q. You discussed uncertainty associated with the pending appeal of Rider VBA. If the Illinois Supreme Court issues an adverse ruling in the Rider VBA case, do the Utilities have a proposal?

A. Yes. As I stated earlier, it is unlikely that a Court ruling will be issued while the record in this case is open. Consequently, the Commission will make its rate design decision with uncertainty about whether the Utilities will have decoupling mechanisms to address Staff's and the intervenors' retreat from gradually increasing fixed cost recovery in fixed charges. Accordingly, it is appropriate for the Commission to address that uncertainty. Of course, one approach would be for the Commission to approve an SFV or modified SFV rate design for S.C. No. 1 HTG and S.C. No. 2. However, given that they still have Rider VBA and in the interests of rate design continuity and gradualism (as discussed in my direct testimony), the Utilities continue to support the proposals described in my direct testimony. However, the Commission's Order can and should address the uncertainty by establishing a clearly defined approach for responding to an adverse Court decision.

Q. How do you recommend that the Commission address the uncertainty of the pending Court challenge to Rider VBA?

A. The Utilities propose that the Commission authorize the Utilities to file revenue neutral cases to implement modified SFV rate designs for S.C. No. 1 HTG and S.C. No. 2 if the Court holds that the Commission lacked authority to approve Rider VBA. The Utilities define, and propose that the Commission likewise define, modified SFV as a rate design that recovers at least 80% of fixed costs through fixed charges. As the Commission has found in prior cases in which it has concluded that 100% of North Shore's and Peoples Gas' costs are fixed, "fixed costs" means customer-classified and demand-classified costs. In the case of S.C. Nos. 1 and 2 the only fixed charge is the customer charge. As previously stated, the Utilities rate design proposals in this proceeding for fixed cost recovery through the customer charge for S.C. No. 1 NH for both Utilities is proposed to be set at 90% recovery, S. C. No. 1 HTG is proposed at 80% for North Shore and 75% for Peoples Gas, and S.C. No. 2 is proposed to be set at 68% and 46% for North Shore and Peoples Gas, respectively. Accordingly, regardless of the rate design approved by the Commission in this proceeding, if the Court issues an adverse ruling, the Commission should authorize the Utilities to make the following revenue neutral tariff filings:

- for S.C. No. 1 NH and HTG, rate designs that set the fixed cost recovery through the customer charge at 80%; and
- for S.C. No. 2, rate designs that (1) set the fixed cost recovery through each Meter Class customer charge at 80%, and (2) set flat distribution charges for each Meter Class to recover the remaining non-storage related fixed costs.

IV. <u>RATE DESIGN AND RATE INCREASE</u>

A. <u>Summary</u>

Q. Please summarize the rate design issues addressed in the direct testimony of parties in this proceeding.

A. Staff witness Mr. Johnson proposes that the Commission move away from what he calls an SFV-based rate design and instead limit customer charges to ECOSS customer classified costs, and base what he calls distribution\demand[3] charges upon ECOSS demand classified costs. This ultimately means moving towards customer charges recovering 100% of customer costs and distribution and, where applicable, demand charges recovering all remaining non-storage related fixed costs.

AG/ELPC witness Mr. Rubin proposes that any increases to the revenue requirement allocated to the S.C. No. 1 NH and HTG rate designs be collected solely through increases in the volumetric charges. He argues that the customer charges be held or even reduced from current levels. (Curiously, Mr. Rubin cited the stabilizing effects of Rider VBA without acknowledging that the AG is challenging the Commission's authority to approve a decoupling mechanism.)

AG witness Mr. Colton purports to support Mr. Rubin's recommendations by contending that the Utilities' rate design disproportionately allocates the proposed rate increase to low use customers, which he states tend to be low income customers.

IIEC witness Mr. Collins proposes certain changes to the ECOSS that he would effectuate in rate design as an across-the-board increase for both North Shore's and Peoples Gas' service classifications.

Q. Based on your analysis of the rate design proposals of the parties in this proceeding, are you proposing any rate design changes in your rebuttal testimony?

A. No. As stated in my direct testimony (Egelhoff Dir., NS Ex. 15.0, 1:20 – 2:23; Egelhoff Dir., PGL Ex. 15.0 REV, 1:20 – 2:23) the Utilities' proposed rate design aligns revenues with costs and continues to concur with the Commission's objectives of continuity and

[3] As Mr. Johnson stated in a data response (NS-PGL 2.30), distribution charges and demand charges are not the same thing. He is apparently using "distribution\demand" charge as shorthand for cost recovery through a distribution charge, a demand charge, or both.

gradualism. Additionally, as stated previously, this rate design will send more appropriate price signals to customers about the fixed costs underlying their delivery service. The Utilities are, however, requesting, in Section III of this testimony, that the Commission approve an approach for addressing a possible court's adverse ruling on Rider VBA.

B. <u>S.C. No. 1, Small Residential Non-Heating</u>

Q. Staff witness Mr. Johnson does not oppose the Utilities' S.C. No. 1 NH rate designs, but he qualifies his testimony with the condition that the customer charge revenues should not exceed 100% of customer costs from the ECOSS. Johnson Dir., Staff Ex. 4.0, 27:621-631; 45:1009 – 46:1019. Please comment.

A. The proposed customer charges under the S.C. No. 1 NH rate design for each of the Utilities is currently set to recover approximately 90% of all non-storage related fixed costs which results in 97% of customer cost recovery. The remainder of the customer costs and all of the non-storage related demand costs would be recovered through the distribution charge. Mr. Johnson supports the Utilities' S.C. No. 1 NH rate designs because less than 100% of customer costs would be recovered through the fixed customer charges. The Utilities oppose his conditional approval that the Utilities' total customer charge revenues derived under the Utilities' proposed rate designs and the final Commission approved ECOSS should not result in more than customer cost recovery through the customer charge. As explained in direct testimony (Egelhoff Dir., NS Ex. 15.0, 9:176-178; Egelhoff Dir., PGL Ex. 15.0 REV, 9:175-177) all of the Utilities' costs recovered through base rates are fixed. Although Mr. Johnson argues that demand costs should be allocated based on the demand a customer places on the Utilities' systems, the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. These demand costs are fixed, and Mr. Johnson does not appear to disagree as confirmed in his response to Utilities' data request Staff NS-PGL 2.29.

Q. AG/ELPC witness Mr. Rubin proposes that no more than 75% of the S.C. No. 1 NH revenues for North Shore and Peoples Gas be recovered through customer charges (Rubin Dir., AG/ELPC Ex. 3.0, 22:470-471; 29:579-580)[4]. Do you agree?

A. No. First, Mr. Rubin provides no basis for these percentages other than to cap the customer charges at their current levels. He claims that "[t]his change will start the process of restoring [Peoples Gas'] residential customer charges to more traditional levels" (Rubin Dir., AG/ELPC Ex. 3.0, 24:491-492; *also see* 30:609-611). He also alleges this will give customers more control over their bills and alleviate some impacts on low-income customers. Rubin Dir., AG/ELPC Ex. 3.0, 24:492-495; 30:611-614.

Second, Mr. Rubin's proposals would result in the Utilities' recovering less than 100% of customer costs through the customer charges (approximately 84% for North Shore and 81% for Peoples Gas). His proposal departs even more substantially than Staff's from Commission policy of moving more fixed cost recovery into fixed charges. It appears undisputed that customer-classified costs are fixed and, even in a rate design that does not place all fixed costs in fixed charges, at least these customer costs ought to be recovered in fixed charges.

[4] Mr. Rubin offers ranges of fixed cost recovery through the customer charge if the Commission determines that the Utilities should receive lower rate increases than the Utilities requested (Rubin Dir., AG/ELPC Ex. 3.0, 25:502-503; 30:606-608).

C. S.C. No. 1, Small Residential Heating

Q. What are Staff witness Mr. Johnson's proposals for the Utilities' S.C. No. 1 HTG rate design?

A. Mr. Johnson proposes that the S.C. No. 1 HTG customer charge recover 100% of the ECOSS customer costs and that all remaining non-storage related fixed costs be recovered through the flat distribution charge (Johnson Dir., Staff Ex. 4.0, 30:685-686; 48:1072-1073). Under Staff's proposals the percentage of non-storage related fixed costs being recovered through the customer (fixed) charge is approximately 66% for North Shore and 59% for Peoples Gas.

Q. Do you agree with Staff's rate design proposals?

A. No. As explained in direct testimony (Egelhoff Dir., NS Ex. 15.0, 9:176-178; Egelhoff Dir., PGL Ex. 15.0 REV, 9:175-177) all of the Utilities' costs recovered through base rates are fixed. Although Staff witness Mr. Johnson argues that demand costs should be allocated based on the demand a customer places on the Utilities' systems, the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. These demand costs are fixed, and Mr. Johnson does not appear to disagree as confirmed in his response to Utilities' data request Staff NS-PGL 2.29.

However, if the Commission adopts Staff's proposal, there is an error in how Mr. Johnson calculated the charges. Although he used the supporting rate design workpapers from my direct testimony to make his calculations, he backed into the charges rather than changing the formulas. Correcting the formulas effects no change to Mr. Johnson's proposed charges for Peoples Gas ($32.35 customer charge and 22.063 cents distribution charge). However, it does create an inconsistency for North Shore. Under Mr. Johnson's proposal for North Shore the customer charge would be $25.00 (instead of $24.95) and the distribution charge would be 11.544 cents (instead of 11.592 cents). More importantly, irrespective of the rate design the Commission orders, the Utilities should calculate rates based on the revenue requirement approved in the Final Order using the Utilities' ECOSS and rate design workpapers adjusted for the allocations and rate designs approved in the Final Order.

Q. AG/ELPC witness Mr. Rubin proposes that no more than approximately 50% of the S.C. No. 1 HTG revenues for North Shore and Peoples Gas be recovered through customer charges (Rubin Dir., AG/ELPC Ex. 3.0, 22:470-471; 29:579-580)[5]. Do you agree?

A. No, for the same reasons as noted with Mr. Rubin's S.C. No. 1 NH proposals. Additionally, as mentioned in the Fixed Cost Recovery section of my rebuttal testimony, gas costs remain a large part of a residential heating customer's annual bill and these costs are appropriate price signals for customer to align conservation with reduced costs. Fixed costs do not provide these same price signals. It should be noted that Mr. Rubin's proposals would result in the Utilities' recovering less than 100% of customer costs through the S.C. No. 1 HTG customer charges (approximately 94% for North Shore and 79% for Peoples Gas).

D. S.C. No. 2, General Service

Q. What are Staff witness Mr. Johnson's rate design proposals for the Utilities' S.C. No. 2?

[5] Mr. Rubin offers ranges of fixed cost recovery through the customer charge if the Commission determines that the Utilities should receive lower rate increases than the Utilities requested (Rubin Dir., AG/ELPC Ex. 3.0, 24:500 – 25:501; 30:605-606).

A. Mr. Johnson proposes that the S.C. No. 2 customer charge recover 100% of the ECOSS customer costs and a portion of the remaining non-storage related fixed costs. He proposes to gradually shift recovery of all non-storage related demand costs to the distribution charges. In this proceeding, his proposal is to decrease the percentage of non-storage related demand costs recovered through the customer charge for North Shore's Meter Classes 1 and 2 from 45% to 40% and Meter Class 3 from 35% to 31% and for Peoples Gas' Meter Classes 1, 2, and 3 from 40%, 45% and 10%, respectively to 36%, 40%, and 9%, respectively. Johnson Dir., Staff Ex. 4.0, 35:805 – 36:818.

Q. Do you agree with his rate design proposals?

A. No. As explained in my direct testimony and mentioned above (Egelhoff Dir., NS Ex. 15.0 9:176-178; Egelhoff Dir., PGL Ex. 15.0 REV, 9:175-177) all of the Utilities' costs recovered through base rates are fixed. Although Staff witness Mr. Johnson argues that demand costs should be allocated based on the demand a customer places on the Utilities' systems, the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. These demand costs are fixed, and Mr. Johnson does not appear to disagree as confirmed in his response to Utilities data request Staff NS-PGL 2.29.

Q. Staff witness Mr. Johnson presents different S.C. No. 2 scenarios. Please comment.

A. Mr. Johnson presented three scenarios that represent different percent recovery of non-storage demand costs through the customer charges for S.C. No. 2 Meter Classes 1, 2, and 3. Scenario 1, assumes the non-storage demand cost recovery through the customer charge of each meter class remains as the current Commission approved percentages, Scenario 2 reduces that recovery by 25%, and Scenario 3 removes all non-storage demand cost recovery from the customer charges.

The Utilities oppose all three of Mr. Johnson's scenarios for the reasons previously stated. Reducing the recovery of fixed costs through the fixed customer charge is contrary to previous Commission rulings and does not send the proper price signals to customers. However, if the Commission decides not to increase the fixed cost recovery in the fixed customer charge, then the Utilities propose the Commission should keep the fixed cost recovery for S.C. No. 2 unchanged from the present rate design, which is Mr. Johnson's Scenario 1.

E. <u>Impact on Total Base Rate Revenue Recovery</u>

Q. How do Staff witness Mr. Johnson's and AG/ELPC witness Mr. Rubin's rate design proposals for S.C. No. 1 HTG and NH and S.C. No. 2[6] impact total base rate revenue recovery?

A. Under Mr. Johnson's rate design proposals for S.C. No. 1 HTG and S.C. No. 2, base rate revenue recovery through fixed costs will be reduced to approximately 65% for North Shore and 54% for Peoples Gas. Mr. Rubin's rate design proposals for S.C. No. 1 NH and HTG would reduce the total base rate revenue recovery through fixed charges to approximately 64% for North Shore and 48% for Peoples Gas. The current rate designs approved by the Commission result in a total base rate revenue recovery through fixed charges of approximately 67% and 55% for North Shore and Peoples Gas, respectively. Reducing fixed cost recovery through fixed costs goes against previous Commission rulings as discussed in the previous Fixed Cost Recovery section.

[6] Mr. Rubin's proposals are limited to S.C. No. 1.

Q. What are the Utilities' rate design proposals for S.C. No. 1 NH and HTG and S.C. No. 2 and impact to total base rate revenue recovery?

A. The Utilities' proposals remain the same as those proposed in my direct testimony and summarized in NS Ex. 15.4 and PGL Ex. 15.4. Together with the rate design proposals of the other service classifications these proposals would result in total base rate revenue recovery through fixed costs of approximately 75% for North Shore and 62% for Peoples Gas.

F. <u>Revenue Deficiency Allocation</u>

Q. IIEC witness Mr. Collins recommends an across-the-board increase for both Peoples Gas and North Shore. Do you agree?

A. No. The Utilities primarily base their rate design on the ECOSS. The only reason Mr. Collins gives for an across-the-board increase is his claim that there are flaws in the Utilities' ECOSSs (Collins Dir., IIEC Ex. 1.0, 24:532-533). Utilities witness Ms. Hoffman Malueg refutes these claims in her rebuttal testimony (NS-PGL Ex. 28.0). Notwithstanding his failure to support an across-the-board increase, it is contrary to the Utilities' practice of creating rate designs that support cost-based rates and sound ratemaking principles (Egelhoff Dir., NS Ex. 15.0, 6:115-119; Egelhoff Dir., PGL Ex. 15.0 REV, 6:116-120). Mr. Collins states that this across-the-board approach is supported by the modified cost of service studies sponsored by his colleague, Ms. Amanda M. Alderson, and yet these cost of service studies show that each service class causes different allocations of the proposed revenue deficiencies. IIEC has failed to provide support for an across-the-board increase or to address how these resulting costs should be used to set rates. IIEC has failed to offer any rates and bill impacts that would result if such an allocation were approved. In addition, the proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. Furthermore, Mr. Collins has failed to address how his proposal would impact the recovery of cost based storage costs recovered under Rider SSC, Storage Service Charge, as well as the determination of baseline uncollectible amounts by service classification that are reconciled under Rider UEA, Uncollectible Expense Adjustment, for recovery of delivery related uncollectible accounts expense. Therefore, his proposal is incomplete and unsupported and should not be approved.

G. Low Income and Low Use Customers

Q. AG witness Mr. Colton questions the Utilities' definition of "low income" that was the basis for the Utilities' response to certain data requests. Could the Utilities have responded to those data requests using Mr. Colton's definition?

A. No. The Utilities do not maintain income data on their customers, nor does Mr. Colton believe they have this information (response to NSPGL-AG 2.07). The Utilities can only identify those customers who receive LIHEAP grants or who participate in the percentage of income payment program (PIPP) as low income customers. The Utilities have no data that support designating other customers as "low income" (however defined) and draw conclusions about the impact of their rate design on these other customers.

Q. Do the Utilities' rate design proposals unfairly affect low use customers?

A. No. The Utilities incur fixed costs to serve their customers. As previously explained, these costs are not dependent on how much gas a customer uses. The fixed costs are the same to provide service to a low-use customer as a high-use customer within the same service classification and, for S.C. No. 1, based on the heating and non-heating rate bifurcation. A low-use customer will realize a lower total bill than a high-use customer through the gas costs and state and local taxes that the Utilities must collect, both of which do vary based on the usage of each customer.

Q. Do AG witness Mr. Colton's observations support changes to the Utilities' proposed rate designs?

A. No. The Utilities responded to the Commission's concerns about distinguishing low use and high use residential customers by proposing S.C. No. 1 NH and HTG, which the Commission approved. S.C. No. 1 NH rates accurately reflect the lower costs of serving these lower use customers who place less demand on the system. The Utilities do not have service classifications based on customer's income, nor do they agree that subsidizing low use customers on the premise that it may be beneficial to low income and elderly customers is a sound rate design. However, low income customers' needs are addressed through targeted assistance programs that are available irrespective of a customer's usage levels. Thus, even low income customers with higher than average use (as may be the case for Peoples Gas' customers (Colton Dir., AG Ex. 4.0C, 11:5-8)) may be eligible for assistance. The Utilities also offer energy efficiency programs and on-bill financing programs that are available to all customers, encouraging them to adopt energy efficiency measures and practices. On-bill financing, which is a vehicle for purchasing energy efficiency measures through loans of up to ten years, is an alternative for certain low income customers who would otherwise find energy efficiency measures difficult to afford. And finally, Mr. Colton's utility-specific data do not even support his theories because Peoples Gas' data do not show the low-use to low-income correlation that he infers (Colton Dir., AG Ex. 4.0C, 11:8-11). It should also be noted that Mr. Colton incorrectly stated that both Utilities show that weather-normalized usage for low income customers is 1,062.86 therms per year and a typical (average) residential customer uses 1,297.68 therms.[7] This is true only for North Shore. Peoples Gas' data actually shows that low income customers use 1,258.60 therms per year and a typical residential customer use less at 1,066.62 therms per year.

V. OTHER TARIFF PROPOSALS

A. Terms and Conditions of Service – Charges

Q. Do you agree with Staff witness Mr. Johnson's recommendation to recalculate the Second Pulse Data Capability charges with the final Commission approved overall rate of return in this proceeding?

A. Yes. Peoples Gas and North Shore will update the Second Pulse Data Capability charges using the approved overall rate of return set by the Commission in the final Order.

B. Rider QIP, Qualifying Infrastructure Plant

Q. Do you agree with Staff witness Ms. Hathhorn's recommendation that a Findings/Ordering paragraph be included in the Final Order of this case (Hathhorn Dir., Staff Ex. 1.0, 26:584 - 27:604)?

A. Yes. Peoples Gas agrees with the recommendation and the language quoted in Ms. Hathhorn's testimony.

Q. What do you recommend regarding any tariff changes to Rider QIP?

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[7] Mr. Colton makes this incorrect reference in two places – Colton Dir., AG Ex. 4.0C, 10:10-12 and Colton Dir., AG Ex. 4.0C, 11:11-13.

A. Staff witness Ms. Hathhorn recommends Peoples Gas revise its Rider QIP tariff to reflect a process to adjust the Rider QIP Surcharge Percentage if its 2014 actual QIP amounts do not equal the 2014 QIP amounts approved in the Commission order. Staff recommends that Peoples Gas use the language proposed in its response to Staff data request PGL DLH 22.03 Revised. Hathhorn Dir., Staff Ex. 1.0, 27:608-610. Peoples Gas does not oppose that proposal, but it has continued to review the language subsequent to serving the referenced data response and the language can be further simplified. Peoples Gas proposes to revise the tariff as shown in NS-PGL Ex. 29.1, which reflects revisions to the response to Staff data request PGL DLH 22.03 Revised. As a result of the proposed changes, Peoples Gas will adjust the Rider QIP Surcharge Percentage ("S%") after new base rates go into effect if its actual 2014 QIP amounts do not equal the 2014 QIP dollar amounts included in rate base as approved in the Commission order. This adjustment will be defined as AdjNetQIP in Rider QIP (see NS-PGL Ex. 29.1) and could be a negative value (if the actual 2014 QIP amounts are less than the QIP related amounts approved in rate base) or a positive value (if the actual 2014 QIP amounts are greater than the QIP related amounts approved in rate base). Consequently, if AdjNetQIP is negative, the Rider QIP S% in 2015 would be negative until the QIP placed in service in 2015 equals the absolute value of the AdjNetQIP. Thus, customers are protected if the QIP amount in rate base is overstated. Alternatively, if AdjNetQIP is greater than zero (as a result of actual 2014 QIP amounts being greater than the QIP amounts approved in rate base in this proceeding), the Rider QIP S% in 2015 will include this 2014 variance in addition to the new QIP placed in service in 2015 and thereafter.

Q. AG witness Mr. Effron proposes reducing the amount of QIP investment included in rate base and states that "[m]aking such a reduction to the forecasted 2014 QIP additions poses little, if any, risk to Peoples Gas." Effron Dir., AG Ex. 1.0, 7:148-149. Mr. Gorman makes a similar comment. Gorman Dir., City/CUB/IIEC Jt. Ex. 1.0, 52:1148-1150. Do you agree with this statement?

A. No. As an initial matter, it is in the best interest of the customers and Peoples Gas to estimate the 2014 QIP related additions that will be included in the revenue requirement set in this proceeding as accurately as possible. Utilities witness Mr. Lazzaro (NS-PGL Ex. 23.0) describes adjustments to 2014 forecasted Accelerated Main Replacement Program ("AMRP") and Calumet Pipeline Project (QIP related) additions to accomplish that objective. Utilities witness John Hengtgen (NS-PGL Ex. 22.0) also addresses impacts of the adjustments to 2014 QIP on rate base. As indicated above, Peoples Gas will adjust the Rider QIP Surcharge Percentage ("S%") after new base rates go into effect if its actual 2014 QIP amounts do not equal the 2014 QIP dollar amounts included in rate base as approved in the Commission order. In addition, any AdjNetQIP will impact the calculation of the Rider QIP cap that limits the S% increase to an annual average of 4%, not to exceed 5.5% in any given year. Inappropriate and unsupported reductions to 2014 QIP would lead to an AdjNetQIP that is greater than zero and could adversely affect Peoples Gas' ability to use Rider QIP. Furthermore, this Rider QIP cap calculation is based on approved base rate revenues (*i.e.*, 4% times base rate revenues). If the appropriate 2014 QIP amount is not included in the approved base rate revenues, the Rider QIP cap will be set lower than reasonable, which further impacts the amount Peoples Gas can spend in subsequent years. Therefore, the amount of 2014 QIP investment that is included in rate base in this proceeding has additional impacts on cost recovery under Rider QIP than mentioned by Mr. Effron and implied by Mr. Gorman.

VI. PUBLIC NOTICES

Q. Have North Shore and Peoples Gas received certificates of publications that show that public notices were published for their proposed rate changes?

A. Yes, certificates of publications are provided in NS-PGL Ex. 29.2. North Shore's publisher's certificate for the Lake County News Sun is provided on page 1. Peoples Gas' publisher's certificate for the Chicago Tribune is provided on page 2.

Q. Does this conclude your rebuttal testimony?

A. Yes.